WINDFARM PREINVESTMENT STUDY

ECONOMIC FEASIBILITY OF WINDFARMS

For :

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I. INTRODUCTION

1.1 Background

An ESMAP mission visited several potential windfarm sites in India in May 1989. These sites had been preselected by the Department of Non-Conventional Energy Sources (DNES), Government of India (GOI). Preliminary analysis and evaluation done by the ESMAP mission on the basis of available data revealed that the most promising sites for further feasibility studies were at Kayathar and Talayathu in Tamil Nadu. It was estimated that the potential at these two sites was 35 MW and 40 MW respectively. The Kayathar site would be an extension of the existing 7.35 MW windfarm at that location.

The ESMAP mission visited India again in April 1990, comprising Michael Crosetti (Mission Leader) and Salim Jabbour (Consultant - Power Economist).1) The Tata Energy Research Institute (TERI) team worked closely with the visiting ESMAP mission, and also had discussions with officials from the Tamil Nadu Electricity Board (TNEB) and Tamil Nadu Energy Department Agency (TEDA). Later, TERI also collected windspeed data from the Indian Meterological Department (IMD).

However, further investigations by COWIconsult in June 1990 revealed that the windfarm capacities of 50 MW and 25 MW at Kayathar and Talayathu respectively would also be suitable. In

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1) Mr. Soeren Arthur Jensen, a wind energy technology expert from COWIconsult (Denmark) was also expected to join the mission in April, but was not able to do so.

particular, the higher capacity at Kayathar would not effect the suitability of the grid. The total installed capacity at the two sites therefore remains unchanged at 75 MW. The analysis presented in the report pertains to these windfarm capacities at the two sites.

1.2 Objectives

TERI were hired as local consultants primarily to collect elevant data from TNEB, IMD and other agencies, and to conduct detailed economic evaluation studies for establishing windfarms at Kayathar and Talayathu. The specific terms-of-reference are :

(i) During the ESMAP mission's visit to India, to review the proposed evaluation methodology and models, and suggest adaptation to local conditions;

(ii) During and after the mission, to collect the data required for analysis from TNEB, IMD and other agencies, as specified by the foreign power economist and the wind energy technology expert;

(iii) During the mission, to get acquainted with the models developed by COWIconsult, the foreign power economist and the mission leader;

(iv) After the mission, to conduct and document sensitivity analysis with the models, based on earlier discussions with the foreign power economist and the data collected.

With the help of the software provided, to assess the onomic impacts of variations in the following factors, among others:

(a) the environmental costs (as estimated in existing literature) that may be associated with both the windfarm and conventional power options;

(b) differences in construction lead times between the windfarm and conventional power options;

(c) the size of the windfarm, i.e. evaluate the economies of scale for these windfarms;

(d) the size of individual wind turbines used, e.g. 100 kW or 225 kW or 450 kW;

(e) the wind resource, in terms of average hourly, daily, or seasonal windspeeds;

(f) fuel costs of the conventional power option; and

(g) capital costs of windfarms and conventional power options.

1.3 Report Layout

The evaluation methodology and models are described in Chapter 2. Chapter 3 presents the data that are used in the analysis, along with sources and assumptions (if any), and also identifies the areas for sensitivity analysis and specifies the sensitivity ranges. Results of base case and sensitivity analysis are presented in Chapter 4; and conclusions and recommendations in Chapter 5.

II. METHODOLOGY

2.1 The Approach

The techno-economic feasibility of 75 MW windfarms at two sites (Kayathar and Talayathu) is assessed. In order to analyze the relative economics of investing in windfarms vis-a-vis other generation options (combustion turbines, combined cycle plants and coal-fired thermal power stations), the methodology adopted is such that the differences in capacity benefits that may be attributed to each technology are also taken into account. The results indicate whether windfarms are economically viable; and if not, which conventional dispatchable technology is most attractive.

As the World Bank considers investment in windfarms at the two sites as one project, the analytical methodology reflects this by evaluating the economics of the combination -- although the differences in the wind potential at the two sites is taken into account.

Suitable models in LOTUS 1-2-3 were made available to TERI by the World Bank mission which visited India in April 1990. These models are for :

(i) estimating monthly production from a windfarm;
(ii) estimating the capacity responsibility of a windfarm; and
(iii) evaluating the relative economics of a windfarm vis-a-vis other generating technologies.

These models are explained briefly in sections 2.2 to 2.4.

2.2 Monthly Windfarm Production Model

The COWIconsult/RISO Windfarm Production (CWP) model calculates the average hourly production from a windfarm for each month. To get the annual production, the model is run twelve times with different sets of monthly average windspeeds. The model gives the combined production from the proposed windfarms at Kayathar and Talayathu.

Hourly windspeed data are used to calculate the monthly average windspeeds for each hour of day. The model uses the Weibull distribution as the windspeed frequency distribution, and the Weibull shape and scale parameters are calculated on the basis of hourly windspeed data. The windspeed is extrapolated to hub-height assuming a logarithmic profile of wind sheer which takes surface roughness into consideration. The Weibull windspeed frequency curve and the turbine power curve are used to estimate the gross hourly energy production of each turbine. Array efficiency, grid availability, turbine availability, air density correction and power losses are taken into account to obtain the net hourly production from the gross production.

The net production of each turbine is multiplied by the number of turbines in the windfarm to give the net windfarm production. The monthly average of specific production on an hourly basis (MWh/MW/hour) for both the sites is then obtained by summing up the net production of the sites and averaging over the total turbine capacity.

2.3 Windfarm Capacity Responsibility Model

This derives the annual capacity responsibility of a windfarm (in terms of MW per MW of installed capacity) using the hourly generation from windfarms in each month (per MW of installed capacity) as obtained from the monthly windfarm production model, and hourly load profiles for each month as obtained from TNEB.

The approach is to: first derive the capacity responsibility of a windfarm for each month on the basis of hourly profiles of unserved energy and windfarm output; and then to derive the annual capacity responsibility by multiplying monthly capacity responsibilities by the respective monthly weights.

The hourly profiles of unserved energy are estimated from the profile of actual loads (MW) at the given system frequency 1), and loads corrected for a frequency of 50 Hz. 2) It is assumed for analytical purposes that the portion of annual total expected unserved energy occuring in any hour is proportional to the difference between the frequency-corrected load and the actual load for that same hour on the peak day of that same month.

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1) The system frequency varies from 48.5 Hz to 51.5 Hz, and is usually below 50 Hz.

2) For particular times when the system frequency exceeds 50 Hz, the difference between corrected load and actual load is taken at 1 MW, for analytical convenience.

The monthly weight is calculated as the maximum difference between frequency corrected load and actual load occuring in any hour during the particular month, divided by the sum of all such values for the entire year.

The mathematical formulation for evaluating the annual windfarm capacity responsibility is given in Annexure II.1.

2.4 **Economic Analysis**

Benefit-cost ratios of windfarms are compared with those of three other technologies (combustion turbines, combined cycle plants, and coal based thermal power stations).

The base year selected for benefit and cost simulations is 1990. All costs that may be incurred in future years (capital investment, fixed O&M costs, variable O&M and fuel costs etc.) are discounted back to the base year, taking into account real cost escalation rates and increases in real interest rates.

All simulations are done for two years only: 1992 and 2000. The first year (1992) is one for which the technology with the shortest lead time is expected to come on-line, if construction begins in the base year. This therefore indicates that the technologies considered have lead times of 2 years or more. The second year (2000) for which simulations are done, is the last year for which benefits and costs associated with different generation technologies can be estimated with a reasonable degree of certainty.

Given for each month in 1990 the hourly load profiles3), the hourly power purchases4) and the hourly generation from hydro power stations5), and the corresponding annual growth rates6) to the years 1992 and 2000, the hourly contributions of thermal power generation in each month are estimated for the two years.

Supply curves for thermal power generation for 1992 and 2000 are computed from available data on system expansion plans and variable fuel and non-fuel operation and maintenance costs of the concerned thermal power stations. For loads that may exceed the output that can be achieved from thermal power stations (and power purchases and hydro power stations), there may be power shortages. Shortage cost estimates are therefore included in the model.

The supply curve for 1992 gives the marginal cost of energy (fuel plus non-fuel variable operating costs) generated from

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3) The actual load in MW at the actual grid frequency.

4) Power purchases include TNEB's share from coal-fired, lignite-fired and nuclear power stations in the central sector, as well as exports to/imports from other states which constitute the southern regional electricity system.

5) This is estimated in the model, given the total annual hydro power generation, and shares of generation during two six-month periods (January to June, and July to December); and the assumption that no hydro power generation occurs in the base load. The hourly hydro power generation profile for each month is estimated as explained in Annexure II.2.

6) Growth rates for annual electricity requirement and power purchases are available from TNEB. These are used to project the hourly load and power purchase profiles. It is assumed that the load curve shape and the hourly profiles of power purchases remain unchanged from 1990 to 1992 and 2000. For hydro power, the annual energy generation levels are forecast by TNEB and assumed for computational purposes. The hourly hydro power generation profile in each month in 1992 is simply scaled up by the ratios of total annual hydro power generation in 1992 and 1990; similarly for the year 2000.

thermal power stations to meet the given loads for each hour in each month. Average transmission and distribution losses incurred in the TNEB system are also taken into account here. The value of wind energy output is then calculated for each hour and each month, as the product of marginal cost of energy from the supply curve and the windfarm output. This process is repeated for the year 2000.

For calculating the benefits associated with investment in the various generation technologies, the delivered energy value is estimated, both for the windfarms and the other three technologies. This is done for both 1992 and 2000. The delivered energy value for windfarm output is an average value (in Rs/kWh) that may be attributed to the total windfarm output in the entire year. In other words, this gives the avoided fuel cost because of generation achieved from windfarms. For the dispatchable technologies, where the capacity factor can vary according to energy requirement, the delivered energy values are computed for capacity factors varying from 10% to 60%. As it would be desirable to maximize the value of delivered energy from a dispatchable technology for any given capacity factor, this is ensured by first sorting in descending order the marginal energy costs for each hour and month, and then ensuring that the generation occurs only during a fixed number of hours according to the capacity factor. The results obtained at this stage indicate the capacity factor of dispatchable technologies, upto which the avoided fuel cost from windfarms exceeds the marginal fuel plus non-fuel variable operating costs of dispatchable technologies.

The delivered energy values are computed for the years 1992 and 2000, and their annual average growth rate during the eight year period is determined. If this growth rate is negative or more than the escalation rate for unserved energy cost, then it is restricted to the escalation rate for unserved energy cost for beyond the year 2000 -- which means that any windfarm established will help to meet some energy shortages. If the rate of growth of delivered energy values is positive but less than that for unserved energy costs, then it is assumed to remain unchanged beyond the year 2000 also.

The energy benefit that may be attributed to windfarms and each of the dispatchable technologies is computed, taking into account suitable growth rates of delivered energy values, discount rates and so forth. This gives the avoided fuel costs from existing or committed capacity (as per TNEB's expansion program) if 1 MW of new capacity (windfarms, combustion turbine, combined cycle plant or steam turbine) is added. This computation is done for capacity factors under consideration.7)

The energy values for windfarms and each of the dispatchable thermal generation technologies are summed up from the year 1990 through the end of their respective economic life time. For this summation, it is assumed that the construction work begins in the base year (1990); therefore the last year for summation

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7) 10% through 60% for dispatchable technologies; and as per the outputs of the monthly windfarm production model and the capacity responsibility model.

corresponds to the construction lead time plus the economic life span.

For computing the capacity benefits associated with different technologies, the avoided capacity cost in TNEB's planned expansion program is considered. For this, effective capacities of the various technologies, and suitable capital recovery factors and present value factors are taken into account. Capital costs so obtained are levelized, as per the capacity factors under consideration.

The energy and capacity benefits thus computed estimate the avoided (capital and running) costs associated with the marginal unit of capacity in TNEB's planned expansion program.

The ratio of the sum of levelized capacity and energy benefits, and the marginal (capital and running) costs of generation as per TNEB's planned expansion program give the benefit-cost ratios of the various technologies.

Annexure II.3 traces the procedure for the estimation of benefits and costs associated with the various generation options.

III. DATA BASE

3.1 Introduction

TNEB generates power from its thermal and hydro power stations as well as some windfarms. It also purchases power from central sector power stations[1] which are : (i) lignite based thermal power stations operated by the Neyveli Lignite Corporation (NLC); (ii) the Madras Atomic Power Plant (MAPP); and (iii) Ramagundam Super Thermal Power Station (STPS) of the National Thermal Power Corporation (NTPC). TNEB also purchases power from the Madras Refineries Ltd. (MRL). In addition, being one of the constituent SEBs in the Southern Regional Electricity Board (SREB), the TNEB also has import/export arrangements with the other states of the region -- Andhra Pradesh, Karnataka and Kerala.

The data collected for the TNEB system for carrying out detailed feasibility studies for windfarms at Kayathar and Thalayatu are described in sections 3.2 through 3.8. These data are used in the models explained in Chapter II.

3.2 Load Forecast and System Expansion

Power demand forecasts are revised every two to three years in India. The most comprehensive and representative forecasts are those of the Power Survey Committee (PSC). The PSC has been established by the GOIs Department of Power (DOP) under the

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1) Central sector power stations are owned and operated by utilities which supply power to all states/union territories which constitute the regional electricity grid system. The sales from each central sector power station to each state/union territory are as per some pre-determined shares.

Central Electricity Authority (CEA).[2)]

Load forecasts from the PSCs most recently completed thirteenth Annual Power Survey (APS) are given in Table 3.1. Table 3.1 also presents the load forecasts prepared by TNEB which will feed in to the discussion process for the PSCs fourteenth APS.[3)] It may be noted from Table 3.1 that TNEB's proposed projections for the fourteenth APS are higher than those of the thirteenth APS.

As per demand forecasts presented in the thirteenth APS, the total energy requirements are expected to increase at the rate of 8.74 per cent per annum during the ten year period 1990 to 2000.

As of 31 March 1990, the installed capacity in the TNEB system plus TNEB's share of central sector projects was 5475 MW. According to present plans, the generating capacity at TNEBs command will increase by 1995 MW during the Eighth Five Year Plan (FYP) period (1990 to 1995). This is as much as 36 per cent of the existing capacity and includes TNEB's central sector share.

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2) Various electric power utilities are represented on the PSC. The normal practice is that state electricity boards (SEBs) and other power utilities that are responsible for generation and distribution of electric power in a particular state/union territory, prepare a load forecast for their respective state/union territory, and submit it to the PSC. The PSC then reconciles these load forecasts with the national level forecasts prepared in-house in the CEA. Normally, this reconciliation process involves a downward revision of the load forecasts made by the SEBs and other utilities.

3) Discussions for finalizing the fourteenth APS were initiated in mid-1989. The PSC report of the fourteenth APS is anticipated to be finalized during 1990/91.

In the Ninth FYP period (1995 to 2000), TNEB's planned capacity additions amount to 2503 MW if its anticipated share from new central sector projects (which are not yet committed) is included, and 1480 MW if this tentatively estimated share is excluded. These additions include hydro, thermal, nuclear and windfarm capacities.

Table 3.1 compares the demand forecasts to the year 2000 with the planned and effective installed capacities. The effective installed capacity takes into account the forced outage rates (FOR) and the maintenance outage rates (MOR) for the different technologies in the generation mix. Data on FOR and MOR

Table 3.1 : Demand Forecasts and Planned Capacities (MW)

	1990	1995	2000
Demand Forecasts			
1) As per the 13th APS	2929	5792*	8558**
2) Proposed by TNEB for the 14th APS		6345	10191
Planned Installed Capacity			
1) Excluding central sector share in 9th FYP period	5475	7469.75	8949.75
2) Including central sector share in 9th FYP period	5475	7469.75	9972.75
Effective Installed Capacity			
1) Excluding central sector share in 9th FYP period	4050	5421	6455.23
2) Including central sector share in 9th FYP period	4050	5421	7229.43

* corresponding to an energy requirement of 30614 GWh.
** corresponding to an energy requirement of 44982 GWh.

Source : Personal communication, TNEB.

are presented in section 3.5.[4] Annexure III.1 gives TNEB's planned capacity additions in greater detail.

Table 3.1 shows that the demand forecasts for the years 1995 and 2000 exceed the effective capacities based on planned capacity additions. Even if one were to take the lower demand forecasts of 5792 MW in 1995 and 8558 MW in year 2000, and the more optimistic capacity plans (to include tentative central sector share of TNEB in Ninth FYP period), the effective capacities at 5421 MW for 1995 and 7229 MW for 2000 fall short of the power demand. It is clear therefore, that power shortages in Tamil Nadu are likely to continue in the forseeable future.

TNEB's total net power purchases (drawal from central sector projects plus net imports from other states in the Southern region) in 1990 were 6837 GWh. According to present expectations, they are expected to increase to 16487 GWh in the year 2000 (if the generation from new central sector projects that have not yet been committed is included) at the rate of 9.20 per cent per annum. However, if the central sector projects which are not yet committed are not considered, then the net power purchases will rise to only 8818 GWh by the year 2000, at an average rate of 2.58% per annum. As power purchases comprise largely base load requirements in the TNEB system, 6837 GWh is modelled to correspond to 780.5 MW, which is expected to increase as per

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4) In addition to plant availability factors that may be computed from data presented in section 3.5, total plant availability factors of 80% and 88% are assumed for nuclear and hydro power plants respectively. It may be noted that these availability factors will give somewhat optimistic estimates for effective capacities.

growth rates given above.

According to available estimates, TNEB's hydro power station capacity is likely to increase from 1945 MW at the end of 1990 to 1947.7 MW by 1992, and further on to 2127.7 MW by the year 2000. Corresponding to this capacity increase, the annual generation is projected to increase from 3353 GWh in 1990 to 3357.7 GWh in 1992 and further on to 3417.7 GWh in the year 2000. The seasonality of hydro power generation however, is not likely to be different from that in 1990 -- 40 per cent of the total annual generation during the six months January through June, and 60 per cent during the remaining six months July through December.

3.3 System Load Curves

Despite all power purchase and import/export arrangements, there have been in general, power shortages in Tamil Nadu during the past few years. In fact, similar shortages have also been experienced by other states in the Southern Region. However, owing to good monsoon rains during 1989, when hydro reservoirs were full and hydro generation could be stepped up, shortages have been relatively less since July 1989.

Nevertheless, the TNEB system has continued to operate at less than the stipulated frequency of 50Hz. Discussions with TNEB officials revealed that even during off-peak hours, when certain TNEBs own power stations are available and their generation levels can be stepped up and the system frequency increased to 50 Hz, this is not done. For if this were done, then the TNEB would have to sell power to the other states, or equivalently, reduce its drawal from the central sector power stations.

Figures 3.1 through 3.10 give the grid frequency, observed load curves (at the given grid frequency), and frequency corrected load curves for the TNEB system on typical days in the months of July 1989 to April 1990. As the data were obtained in April, only projected load curves and frequencies for the months of May and June 1990 were available; and are presented in Figures 3.11 and 3.12 respectively.

The graphs show that the morning peak time may, in general, be considered to be from 0600 to 1000 hrs, and the evening peak time from 1800 to 2100 hrs. Table 3.2 shows that for several months, the system load (corrected for frequency variations) is 90% or more than the system peak load during these time intervals. In fact, in all months, the system load exceeds 85% of the system peak load during these morning and evening hours.

Table 3.2 : TNEB -- System Peak Load and Peak Time

	Peak load (MW)	Time for system peak (hrs)	Time (hrs) when load exceeds 90% of system peak	
			Morning	Evening
July 1989	2619	2000	0600-0900	1900-2100
Aug. 1989	2749	2000	0600-1000	1900-2100
Sep. 1989	2789	2000	0700-0900	1800-2100
Oct. 1989	2755	1900	0600	1900-2100
Nov. 1989	2704	2000	0800	1800-2000
Dec. 1989	2998	0800	0600-1000	1600-2000
Jan. 1990	2976	0900	0700-1200	1700-2000
Feb. 1990	3024	0800	0700-1500	1900-2000
Mar. 1990	3147	0800	0600-1200	1400-2400
Apr. 1990	3022	2000	0600-1200	1500-2100
May 1990	2985	0600	0600-0800	1800-2100
June 1990	2967	0600	0500-1000	2000-2100

Source : Personal Communications, DESU.

3.4 Shortage Cost Estimates

It is evident from section 3.2 that significant power shortages are likely to continue in Tamil Nadu during the 1990s. In anticipation that power supply restrictions and brown-outs are likely to continue in the foreseeable future, several industrial and commercial establishments have sought to mitigate their effects by investing in standby generation facilities. Such standby or captive generators are usually diesel generators of less than 100 kVA capacity to as much as 2000-3000 kVA capacity. Investment in these generation facilities is a consequence of decisions made by private entrepreneurs, and is not included in the capacity expansion planning framework of the organized power supply industry (i.e. TNEB and other central sector agencies). These diesel generators use high-speed-diesel (HSD), which is imported at the margin. HSD use for power generation therefore leads to an expenditure of India's scarce foreign exchange resources.

The very fact that private industry prefers to use standby diesel generators when it experiences power shortages indicates that it finds it more economical to do so than to forego production. The costs of investing in, maintaining and operating this back-up source of power generation may therefore be considered as a lower bound for shortage costs. Shortage cost estimates so derived are given in Table 3.3. It is assumed that the diesel generators are used for 2000 hours each year -- a realistic estimate for Tamil Nadu.

On the other hand, the Federation of Indian Chambers of Commerce and Industry (FICCI)5) estimates that the loss of value added in manufacturing industry due to unreliability of power supplies is about Rs.3.00/kWh in financial prices. This corresponds to about Rs 2.40/kWh in economic terms.

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5) FICCI, Self Generation of Power by Industry, Report of a Seminar, New Delhi, June 1988.

Table 3.3: Estimated Costs of Standby Generation Using Diesel Sets

		50 kW machine	200-400 kW machine
A.	Fixed Costs (Rs/kW)		
a.1	Capital cost plus installation charges	6300	4420
a.2	Annualized capital cost	925	649
a.3	Salaries	668	449
a.4	Maintenance	134	92
a.5	Total fixed annual costs	1727	1190
B.	Variable Operating Costs (Rs/kWh)		
b.1	Diesel	1.008	0.806
b.2	Lubricating oil	0.040	0.040
b.3	Total variable cost	1.048	0.846
C.	Total Generation Cost (Rs/kWh)	1.912	1.441

a.1: As given in World Bank's report "Private Power Utilities Project 1".

a.2: Assuming a 15-year life and 12% discount rate.

b.3: Assuming a c.i.f. diesel price of US $ 22.4/bbl or Rs 2.4/liter (US $ 1 = Rs 17.00); storage/handling/transport costs of Rs 0.12/liter; and HSD consumption norm of 0.3 liter/kWh.

b.4: Assuming cost of lube oil as Rs 10/liter (including c.i.f. price, and storage/handling/transport costs) and lube consumption of 0.006 liter/kWh.

c: Assuming capacity factor of 22.8% or annual generation of 2000 kWh/kW of installed capacity.

3.5 Conventional Power Generation Technologies

As evident from Annexure III.1, the TNEB has plans to install hydro power stations, coal-fired steam thermal power stations (TPS) and oil-fired combustion turbines (CTs). It is understood that one gas-fired combined cycle plant (CCP) is also expected to come on stream during the 1990s. It is also anticipated that TNEB's share of coal and lignite based generation capacity and nuclear capacity operated by the central sector agencies will increase.

Discussions with TNEB officials revealed that there is no significant difference between coal-fired and lignite-fired power stations in terms of capital investment requirements, construction lead times, fixed operation and maintenance costs, and so forth. Moreover, reliable data on the cost and performance parameters of nuclear power capacity are not readily available. Furthermore, it is likely that TNEBs investment levels in windfarms will only effect investment progams for thermal capacity in the TNEB system, and expansion of hydropower capacity will continue as planned. Therefore, the relative economics of lignite-fired capacity, nuclear power stations and hydro power capacity vis-a-vis windfarms is not analyzed.

The models explained in Chapter II will only be used for analyzing the economics of coal-fired TPS, CTs, and CCPs vis-a-vis windfarms. The data used for this purpose are given in Table 3.4.

The data in Table 3.4 pertain to recently sanctioned projects : (i) a 3 x 210 MW coal fired TPS; (ii) a 4 x 30 MW CT power plant using HSD; and (iii) a 90 MW CCP running on natural gas. All data are from feasibility reports of the respective projects, and may therefore be somewhat optimistic. The time and cost overruns which are usually experienced towards commissioning a power plant are not accounted for. The overnight capital costs (OCC) in Rs/kW are derived from the total project cost (as sanctioned) and the generation capacity to be installed; and are in constant 1990 prices. To the extent delays occur in power plant construction, the construction time and phasing of capital expenditure per year during the construction time may be somewhat inaccurate.

Data on fixed annual operation and maintenance expenses and auxiliary consumption levels are based on experience in TNEB and other utilities in India, at least for coal-fired TPS and oil-fired CTs; for CCPs, these data are based solely on expectations as stated in the feasibility report, and are not backed by any operational experience in India. The same is largely true also for plant economic life, forced outage rates (FOR) and planned unavailability (maintenance outage rates or MOR) for CTs and CCPs. As far as MOR and FOR for coal-fired TPS are concerned, the norms used by CEA for its planning purposes are also adopted by TNEB, and are used for analytical purposes. However, it may be noted that TNEB assumes the economic life of coal-fired TPS units to be 25 years (which we use for further analysis) while the CEA adopts a norm of 30 years for planning purposes.

Data on present estimates of fuel costs are as given in the specific project feasibility reports; but estimates of fuel price escalations in real terms have been obtained from respective experts with a knowledge of the indigenous coal industry and international oil and gas markets6).

As far as the estimates for environmental costs are concerned, they are as given in a recently completed study that was submitted to the DNES7).

The transmission and distribution losses are taken at 20 per cent of gross generation. This is the average level of T&D losses n the TNEB system.

The real cost escalation rate and the real interest rate -- for interest-during-construction (IDC) and present value (PV)/IDC calculations -- are estimated at about 3 and 2 per cent per annum respectively.

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6) Expectations of international coal market developments and evolution of international coal prices are not considered, because India's non-coking coal requirements are likely to be met largely by the indigenous coal industry, and imports/exports of coal remain negligible.

) Metaplanners and Management Consultants, *A Study on Cost of Electricity Generation and Environmental Aspects*, report submitted to DNES, Patna, September 1989.

Table 3.4 : Cost and Performance Parameters of Conventional Thermal Power Generation Systems

	Coal based TPS	Combustion Turbine (CT)	Combined Cycle Plant (CCP)
Overnight capital cost (Rs/kW)	12,125	10,280	14,020
Construction time (years)	7	4	4
Phasing of capital expenditure (%)			
- Year 1	11.1	9.35	12.5
- Year 2	13.1	26.94	37.5
- Year 3	18.3	31.18	37.5
- Year 4	22.9	32.53	12.5
- Year 5	18.3	NA	NA
- Year 6	13.1	NA	NA
- Year 7	3.2	NA	NA
Fixed O & M costs (% of OCC)	2.5	2	2.5
Fuel Type	Coal; Furnace Oil(FO)	High Speed Diesel (HSD)	Natural Gas
Fuel cost (Rs/kWh gross)	Coal:0.4960[a] FO:0.0307[b]	0.8099[c]	0.5357[d]
Real fuel cost escalation rate (% per annum)	Coal:2.5 FO:2	HSD:2	Gas:2
Aux. consumption (% of gross generation)	8	2	4
Economic life (years)	25	30	25
Forced outage rate (%)	24	15	15
Maintenance outage rate (%)	15	10	10
Environmental costs			
- fixed (% of OCC)	8.6	8.6	8.6
- variable (% of VOC)	7	4	5

a) Cost of delivered coal = Rs 800/tonne; coal consumption of 0.62 kg/kWh.

b) c.i.f. cost of furnace oil = Rs 2000/tonne; storage/handling/transport costs of FO = Rs 100/tonne; FO consumption = 15 ml/kWh; specific gravity of FO = 0.975 kg/liter.

c) c.i.f. cost of HSD = US $ 22.4/bbl or Rs 2.3954/liter (US $ 1 = Rs 17); storage/handling/transport cost = Rs 0.12/liter; calorific value = 8874 kCal/liter; thermal efficiency of CT = 30%.

d) Economic price of natural gas = Rs 2250/thousand standard cubic meter (SCM); calorific value = 9000 kCal/SCM; thermal efficiency of CCP = 40%.

3.6 Marginal Cost of Generation from Thermal Power Stations

As TNEB owned thermal power stations are more expensive to operate than its hydro power stations, and also because TNEB's power purchase quotas are more or less fixed, it turns out that TNEB's own thermal power capacity will be used at the "margin". However, this does not imply that generation from all thermal capacity will need to be changed from hour to hour in line with the load, because the TNEB owned thermal capacity accounts for 35 per cent of the total capacity at TNEBs command (including its share from central sector projects) in 1990. This share is likely to increase to 36 per cent by 1992 and over 50 per cent by the year 2000. It may very well be that the planned additions of CT capacity alone are adequate to mostly handle changes in load from hour to hour.

The background information used for estimating the marginal costs of generation in various thermal power stations is given in Table 3.5. On the basis of this information, the marginal costs of generation are estimated and presented in Table 3.6.

Table 3.5: Variable Operating Cost Parameters of Existing and Planned TNEB Owned Thermal Capacity

	Ennore TPS	Tuticorin TPS	Mettur TPS	North Madras TPS	CT
Fuel used					
- Coal	Yes	Yes	Yes	Yes	No
- Furnace Oil (FO)	Yes	Yes	Yes	Yes	Yes
Average heat rate (kCal/kWh)	2646	2560	2560	2500	2650
Average heat rate met by					
- Coal (%)	95	95	95	95	-
- FO (%)	5	5	5	5	100
Calorific value of fuels (kCal/kg)					
- Coal	4000	4000	4000	4000	N.A.
- FO	9900	9900	9900	9900	9900
Delivered fuel Price (Rs/tonne)					
- Coal	853.38	901.04	909.48	800	N.A.
- FO	2100	2100	2100	2100	2100
Forced outage rate (%)	24	24	24	24	15
Maintenance outage Rate (%)	15	15	15	15	10

Table 3.6: Installed Capacity, Effective Capacity and Variable Operating Costs of Thermal Power Stations

	1992	2000
Installed Capacity (MW)		
- Ennore TPS	450	450
- Tutiorin TPS	840	1050
- Mettur TPS	840	840
- North Madras TPS	-	1630*
- CT	-	730
Effective Capacity (MW)		
- Ennore TPS	290.7	290.7
- Tutiorin TPS	542.64	678.3
- Mettur TPS	542.64	542.64
- North Madras TPS	-	1052.98
- CT	-	558.45
Variable Operating Costs in 1990 prices (Rs/kWh)**		
- Ennore TPS	0.5643	0.5643
- Tutiorin TPS	0.5750	0.5750
- Mettur TPS	0.5801	0.5801
- North Madras TPS	0.5015	0.5015
- CT	0.5621	0.5621

* Includes North Madras TPS Stage II of 1000 MW capacity.
** Excludes real fuel cost escalation rates.

3.7 **Windfarm Specifications**

In their "Note on Windfarm Production Model" (September 1990), COWIconsult have discussed the technical and economic specifications of windfarms in detail. Certain aspects, particularly on costs, which are not very clearly presented in the COWIconsult note are given in Table 3.7. Data in Table 3.7 are used for the base case analysis.

Table 3.7 : Cost Parameters of Windfarms

	Kayathar	Talayathu
Overnight Capital Costs		
- Rs/kW (1989 prices)	17,629	17,995
- Rs/kW (1990 prices)	18,158	18,535
Fixed and Variable O & M costs (Rs/kWh)	0.20	0.20
Construction Time (months)	20	16
Phasing of capital expenditure (%)		
- Year 1	80	90
- Year 2	20	10

Notes : (i) An exchange rate of Rs 15.25/US $ is assumed in the September 1989 COWIconsult note.

(ii) A real cost escalation rate of 3% per annum is assumed.

(iii) The phasing of capital expenditure as given above indicates that for both windfarms together, 83.38% of the capital expenditure is incurred in the first 12 months.

3.8 Sensitivity Analysis

Analytical results obtained by using data presented in sections 3.2 through 3.7 are subject to sensitivity analysis to gauge the implications of changes in values of certain parameters. These parameters are listed in as Table 3.8, along with their base, low and high values for senstivity analyses.

Table 3.8: Parametric Varations for Sensitivity Analysis

	Base	Low	High
(a) **For changes in Benefit-Cost Ratios of the Competing Technologies**			
Overnight Capital Costs (Rs/kW)			
- Coal based TPS	12125	9094	15156
- CT	10280	7710	12850
- CCP	14020	10515	17525
Lead Time (years)			
- Coal based TPS	7	5$	9$$
- CT	4	3$*	5$#
- CCP	4	3$@	5$@$
Real Escalation Rate of Variable Operating Costs (% per year)			
- Coal based TPS	2.5	1	4.5
- CT	2	0	3.5
- CCP	2	0	3.5
- Windfarm	-	-	-
Fixed Environmental Costs (% of OCC)			
- Coal based TPS	8.6	0	17.2
- CT	8.6	0	17.2
- CCP	8.6	0	17.2
- Windfarm	-	-	-
Variable Environmental Costs (% of VOC)			
- Coal based TPS	7	0	14
- CT	4	0	8
- CCP	5	0	10
- Windfarm	-	-	-
Delivery Losses i.e. T&D Plus Auxiliary Consumption Losses (% of gross output)			
- Coal based TPS	28	23	33
- CT	22	17	27
- CCP	24	19	29
- Windfarm	15	10	20
Forced Outage Rates (%)			
- Coal based TPS	24	19	29
- CT	15	10	20
- CCP	15	10	20

	Base	Low	High	
Maintenance Outage Rates (%)				
- Coal based TPS	15	10	20	
- CT	10	5	15	
- CCP	10	5	15	
(b) For Changes in Windfarm Performance and Cost Only				
Turbine Size :				
Wind Resources :	As provided by COWIconsult			
Array Efficiency :	(Sept. 1990)			
Grid & Turbine Availability :				
Overnight Capital Costs (Rs/kW)				
- Kayathar	18158@	14579@@	18158@@@	
- Talayathu	18535@	14945@@	18535@@@	
- Combined	18284@	14701@@	18284@@@	
Annual O&M Costs (Rs/kWh)				
- Kayathar	0.20@	0.19@@	0.20@@@	
- Talayathu	0.20@	0.19@@	0.20@@@	
(c) Other Changes				
Cost of Unserved Energy (Rs/kWh)	1.441	1.243*	3.226**	
Annual Real Discount Rate (%)	12	10	-	
Annual Load Growth Rate (%)	8.74	6.74	10.74	
Capacity accessed by TNEB in 2000 (MW)				
- Central Sector	3031	2008	3031	3031
- Coal/Lignite (excl. central	3970	3970	3970	5470
- CT (excl. central sector)	730	730	2000##	730
- Other	2241.75	2241.75	2241.75	2241.
Total	**9972.75**	**8949.75**	**11242.75**	**1147**

$ The investment is phased in five years in the following manner : 11.1% in the first year, 22.2% in second, 33.3% in third, 22.2% in fourth, and 11.1% in fifth (Source: CEA, Personal Communications).

$$ The investment in nine years is spread approximately as follows : 4% in the first year, 8% in second, 12% in third, 16% in fourth, 20% in fifth, 16% in sixth, 12% in seventh, 8% in eighth and 4% in ninth (Source: CEA, Personal Communications).

$* The investment is phased in 3 years as follows : 25% in the first and third years, and 50% in the second (Source: CEA, Personal Communications).

$# The investment profile during the construction time of five years is approximately as follows : 8% in first year, 24% in second, 26% in third, 27% in fourth and 15% in fifth (Source: CEA, Personal Communications).

$@ No previous experience in India so far; but likely investment profile in three years of construction time is : 25% in the first and third years, and 50% in the second.

$@$ No previous experience in India so far, but likely investment profile in five years of construction time is : 14% in first year, 22.2% in second, 33.3% in third, 22.2% in fourth and 11.1% in fifth.

@ For windfarms having 225 kW Vestas turbines.

@@ For windfarms having 100 kW US WindPower turbines.

@@@ For windfarms having 450 kW Bonus turbines.

* A utilization rate of 3000 kWh/kW per annum is assumed for diesel sets (refer to Table 3.3).

** Assuming an annual utilization rate of 500 kWh/kW for diesel sets (refer to Table 3.3).

Assuming that an additional lignite based power station of 1500 MW comes on stream by 2000. This is included in the TNEB's power expansion programme. Its costs and performance are assumed to be the same as that of the coal based North-Madras TPS.

Assuming that an additional CT of about 1270 MW capacity is commissioned by the year 2000. This additional CT has the same effective capacity (as per base case assumptions of MOR and FOR) as a 1500 MW lignite based TPS.

Fig 3.1: JULY 1989

TNEB System Load

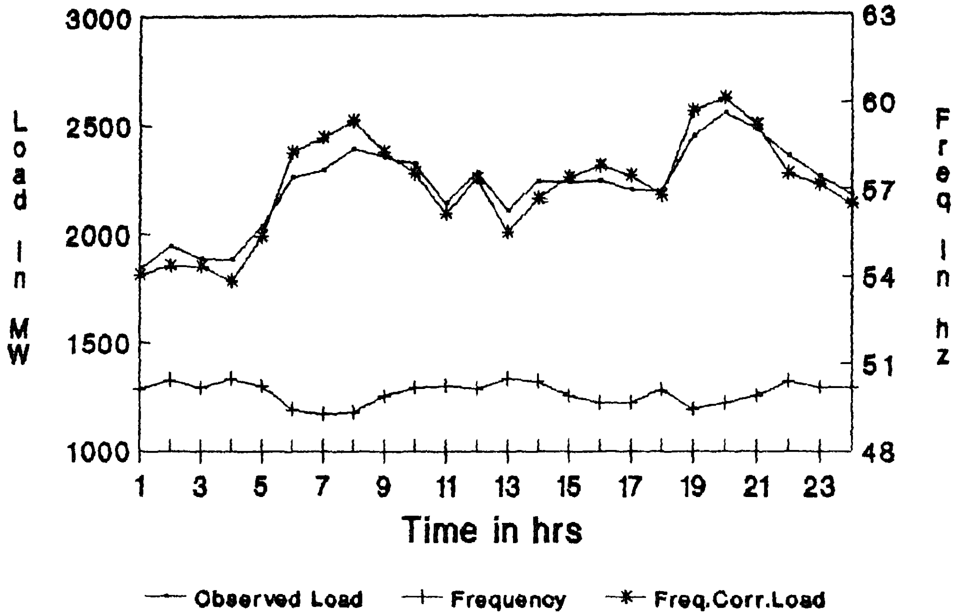


Fig 3.2: AUGUST 1989

TNEB System Load

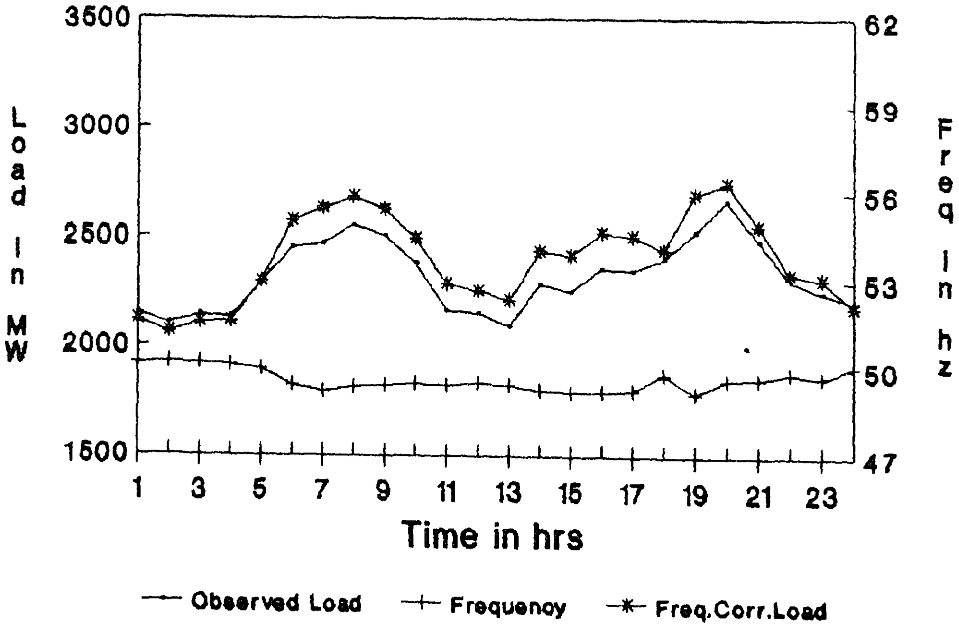


Fig 3.3: SEPTEMBER 1989

TNEB System Load

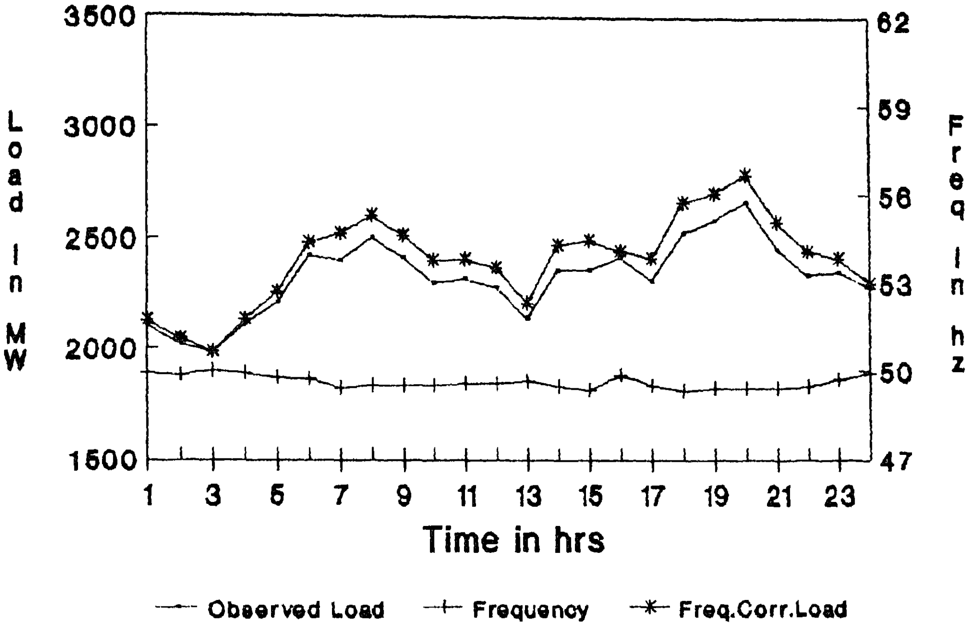


Fig 3.4: OCTOBER 1989

TNEB System Load

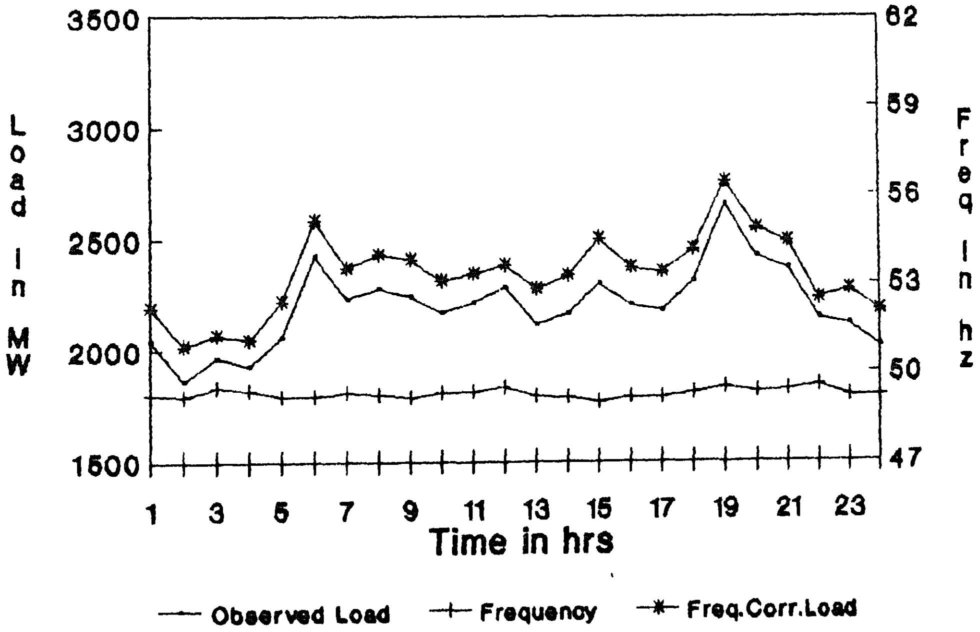


Fig 3.5: NOVEMBER 1989
TNEB System Load

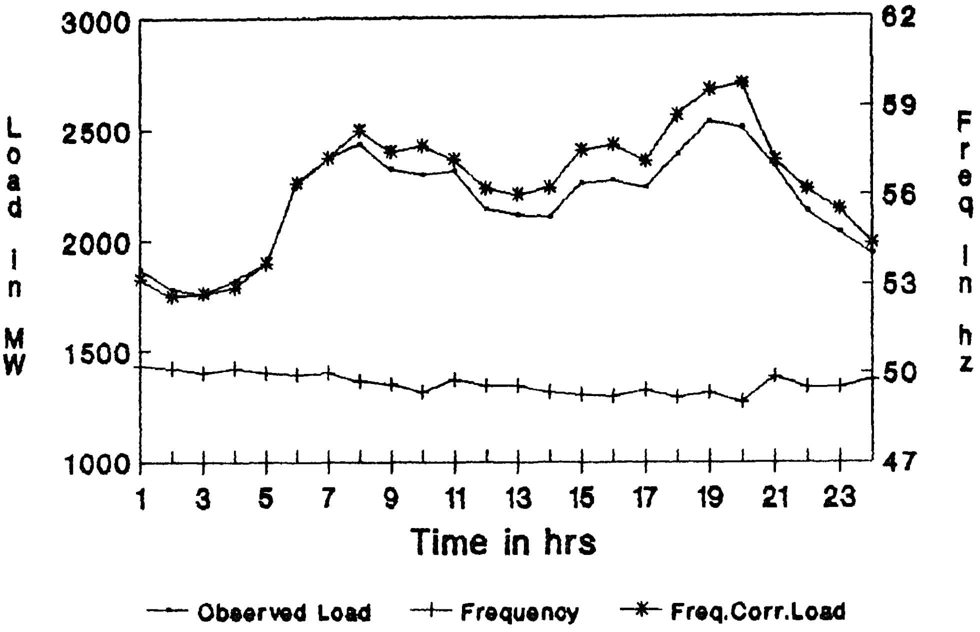


Fig 3.6: DECEMBER 1989
TNEB System Load

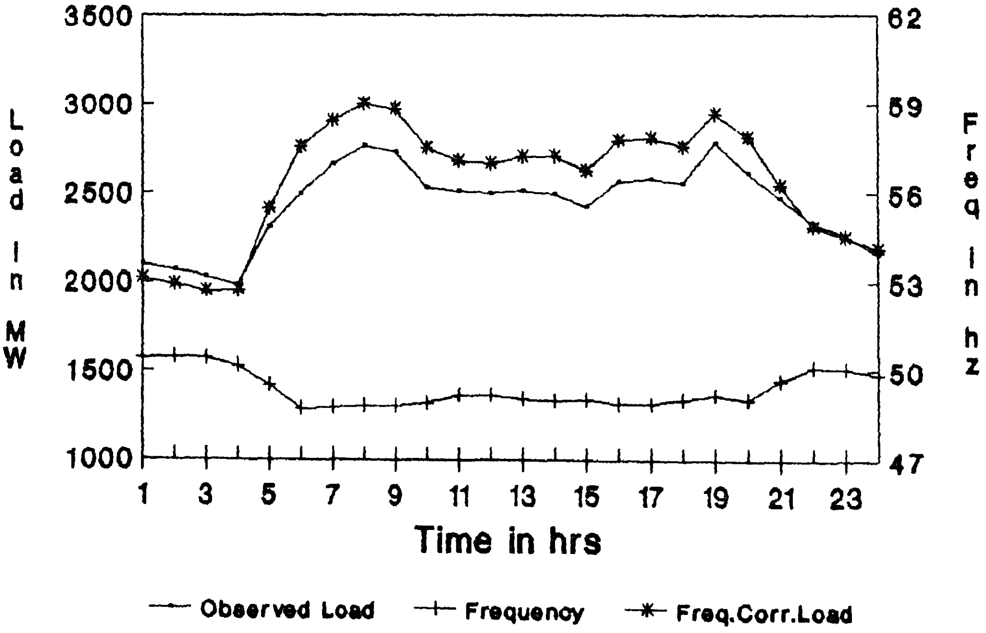


Fig 3.7: JANUARY 1990

TNEB System Load

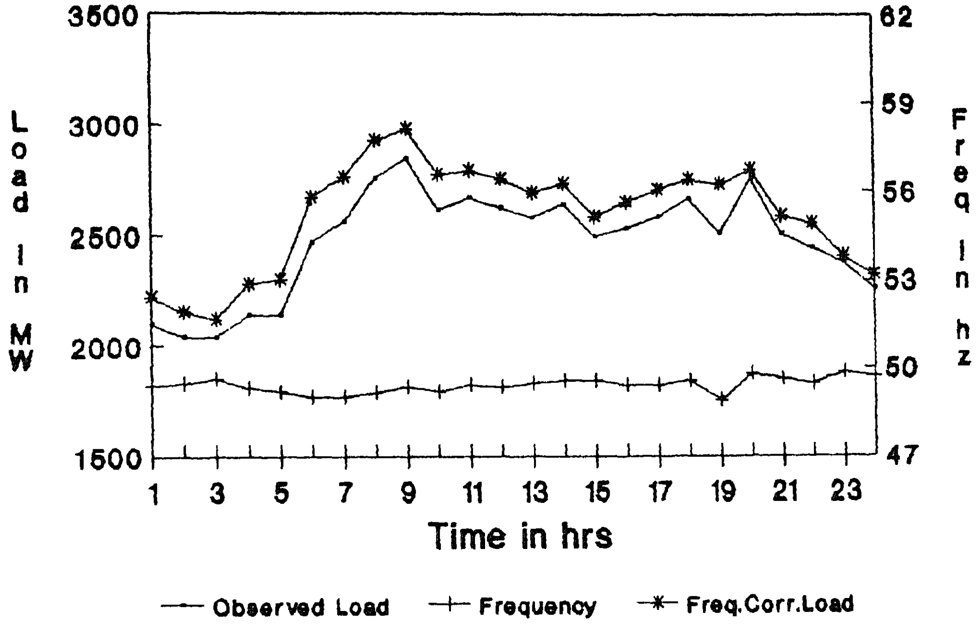


Fig 3.8: FEBRUARY 1990

TNEB System Load

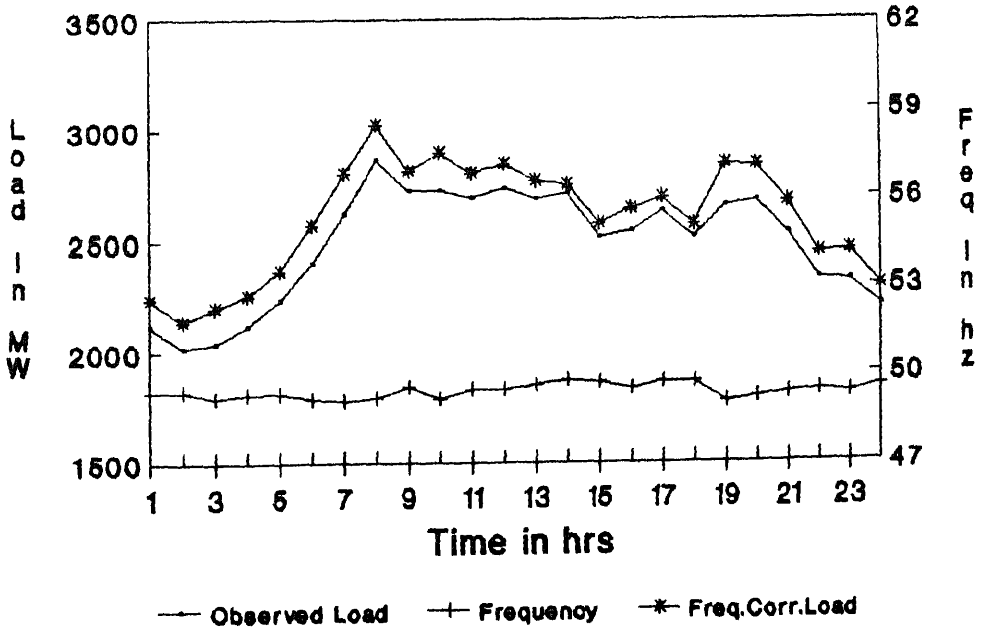


Fig 3.9: MARCH 1990

TNEB System Load

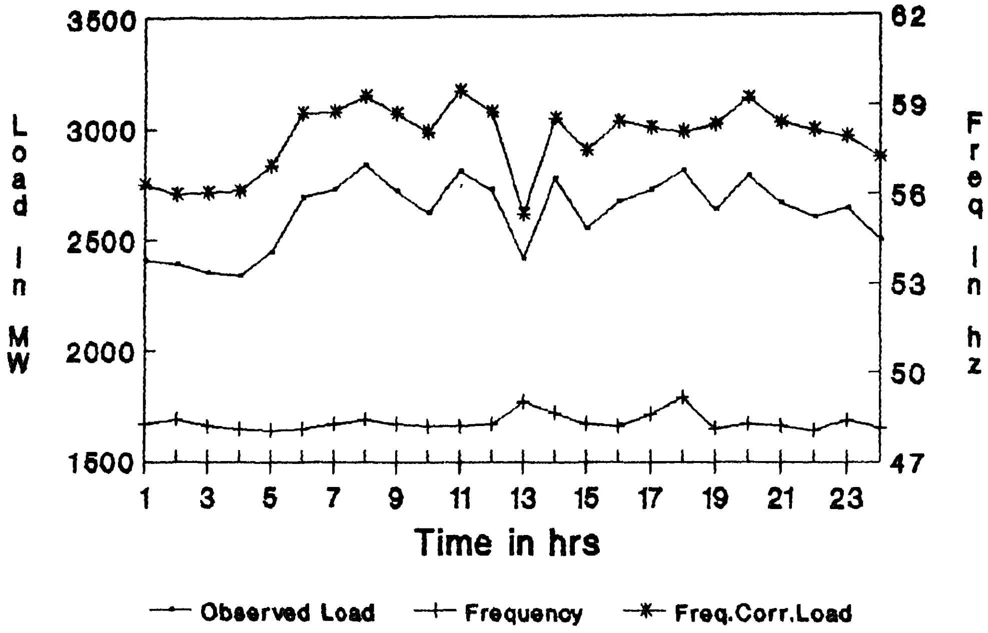
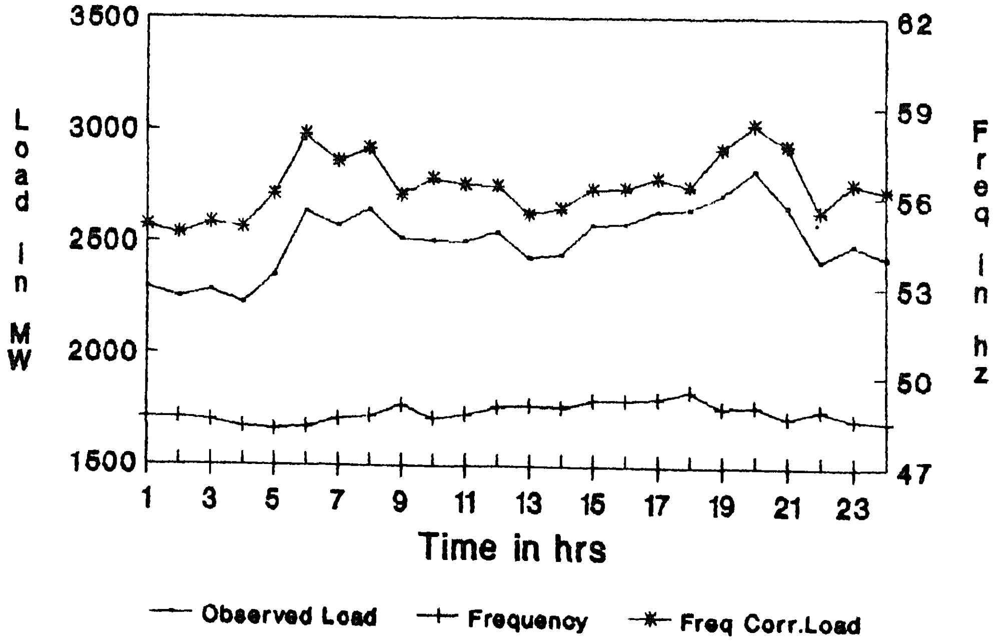


Fig 3.10: APRIL 1990

TNEB System Load



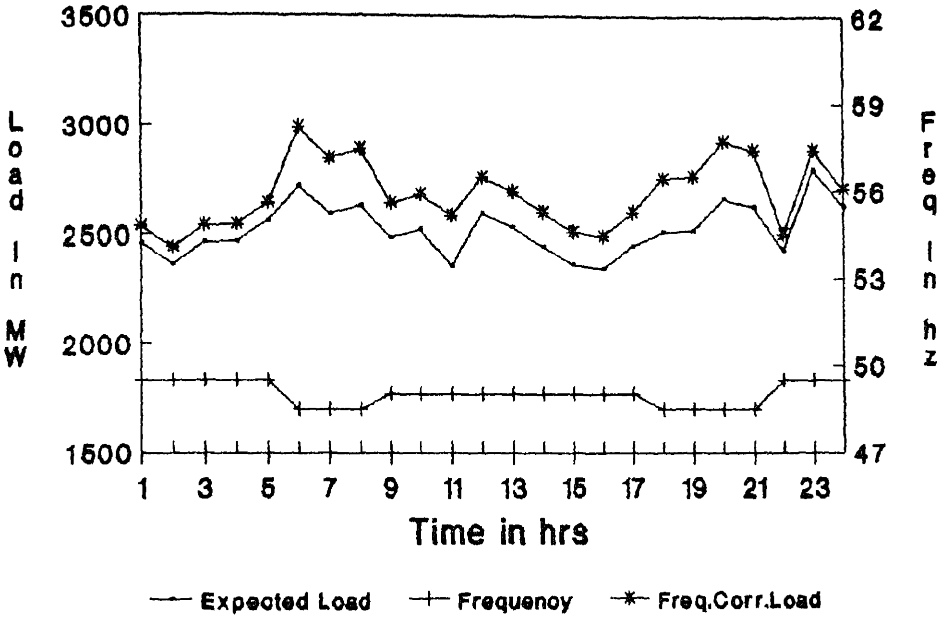


Fig 3.11: MAY 1990

TNEB System Load

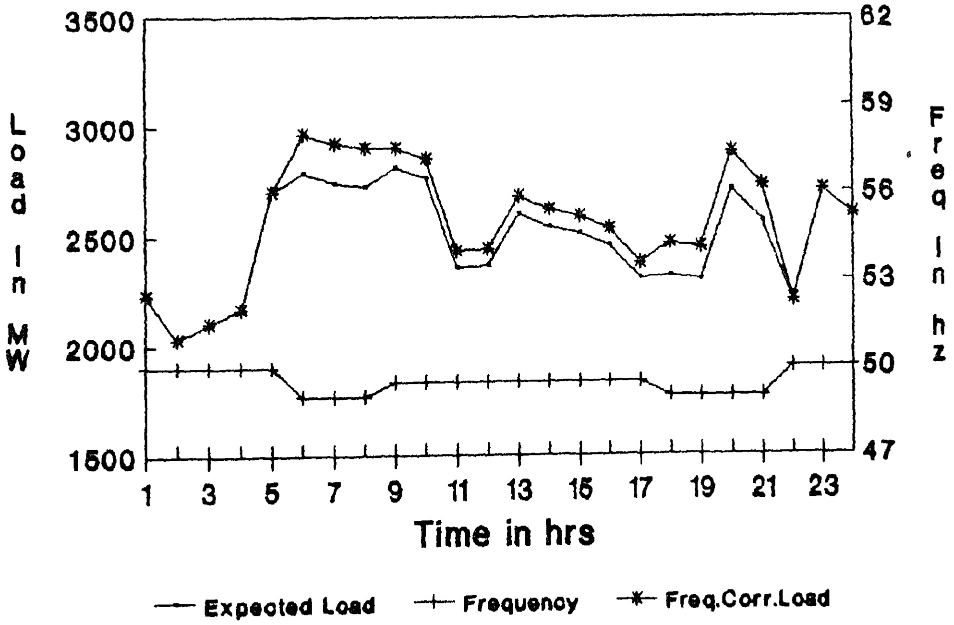


Fig 3.12: JUNE 1990

TNEB System Load

IV. RESULTS

4.1 Introduction

Analytical results obtained with the data presented in Chapter III and the models discussed in Chapter II are summarized below.

TERI received monthly windfarm production results obtained through the CWP model for eight scenarios. These results were fed in to the windfarm capacity responsibility model to yield eight sets of annual windfarm capacity factors and effective capacities. The eight windfarm production scenarios relate primarily to total windfarm size of 75 MW using 225 kW turbines, although windfarms of smaller size and turbines of different ratings are considered in some selected scenarios (Table 4.1).

Table 4.1 : Characterization of Windfarm Output Scenarios

Scenario	Windfarm Size(MW)	Turbine Capacity(kW)	Windspeed	Turbine & Grid Availability
BASE	75	225	Normal	Normal
HIGH	75	225	High	Normal
LOW	75	225	Low	Normal
W450	75	450	Normal	Normal
W100	75	100	Normal	Normal
AVHI	75	225	Normal	High
AVLO	75	225	Normal	Low
SMAL	19.8	225	Normal	Normal

The economic viability of windfarms is analyzed vis-a-vis conventional dispatchable technologies (CTs, CCPs and coal-fired TPSs). Benefit-cost ratios of the various power generation options are computed.

The costs of generation from the conventional dispatchable technologies and the benefits that may be attributed to them, are independent of the windfarm output scenario descriptors (Table 4.1). The benefits and costs associated with CTs, CCPs and coal-fired TPSs instead depend upon factors like construction time, transmission/distribution losses, MOR and FOR and so on. Therefore, the benefit-cost ratio estimates for these technologies are presented in section 4.2, which may then be compared with benefit-cost ratios of windfarms (section 4.3) across all windfarm output scenarios.

4.2 Benefit-Cost Ratios of Conventional Technologies

Benefit-cost ratios of CTs, CCPs and coal based TPSs are computed for the following case/scenario variables :

(i) Base : Using base values for overnight capital costs, construction time, real escalation rates for variable operating costs, fixed and variable environmental costs, delivery losses, FOR and MOR, as given in Table 3.8;

(ii) Low Performance and High Cost : Using high values for the concerned cost and performance parameters (Table 3.8);

(iii) Enhanced Performance and Low Cost : Using low values for the same parameters (Table 3.8); and

(iv) Low Discount Rate : Using base values for the concerned cost and performance parameters (Table 3.8), and a real discount rate for all technologies of 10 per cent per annum.

It may be noted that changes in all cost and performance parameters for the conventional technologies are clubbed together, because changes in one parameter alone leads to insignificant changes in the benefit-cost ratios of the conventional technologies -- and with no change in the ranking of windfarms vis-a-vis conventional technologies.

In each of the four cases, the benefit-cost ratios of CTs, CCPs and coal-fired TPSs are computed for annual capacity factors of 0.1, 0.2, 0.3, 0.4, 0.5 and 0.6.

4.2.1 Base Case

Table 4.2 shows the benefit-cost ratios for CTs, CCPs and coal-fired TPSs under base case conditions.

Table 4.2 : Base Case -- Benefit-Cost Ratios of Conventional Technologies

Capacity Factor (fraction)	B/C Ratios		
	CT*	CCP#	Coal TPS
0.1	1.5522	1.0699	1.0722
0.2	2.2498	1.5621	1.6620
0.3	2.9069	2.0320	2.2211
0.4	3.5484	2.4962	2.7700
0.5	4.0639	2.8748	3.2147
0.6	4.4511	3.1643	3.5524

* PV/IDC multiplier = 0.7938
# PV/IDC multiplier = 0.8124
@ PV/IDC multiplier = 0.7523

4.2.2 Low Performance and High Cost Case

Table 4.3 shows the benefit-cost ratios associated with CTs, CCPs and coal-fired TPSs if their performance levels deteriorate vis-a-vis base case levels, and costs increase. It is clear that B/C ratios here are lower than under base case conditions.

Table 4.3 : Low Performance and High Cost Case — Benefit-Cost Ratios of Conventional Technologies

Capacity Factor (fraction)	B/C Ratios		
	CT*	CCP#	Coal TPS@
0.1	1.1798	0.8197	0.8269
0.2	1.7044	1.1894	1.2961
0.3	2.2018	1.5433	1.7426
0.4	2.6908	1.8941	2.1833
0.5	3.0918	1.1839	2.5466
0.6	3.4021	2.4100	2.8295

* PV/IDC multiplier = 0.7794
# PV/IDC multiplier = 0.7878
@ PV/IDC multiplier = 0.6970

4.2.3 Enhanced Performance and Low Cost Case

Table 4.4 shows the benefit-cost ratios computed for CTs, CCPs and coal based TPSs if their performance improves and their costs reduces from base case levels. These benefit-cost ratios are higher than under base case conditions.

Table 4.4 : Enhanced Performance and Low Cost Case — Benefit-Cost Ratios of Conventional Technologies

Capacity Factor (fraction)	B/C Ratios		
	CT*	CCP#	Coal TPS@
0.1	2.0353	1.4435	1.4941
0.2	2.9880	2.1425	2.3161
0.3	3.8748	2.8062	3.0913
0.4	4.7304	3.4578	3.8480
0.5	5.3998	3.9803	4.4506
0.6	5.8830	4.3698	4.8959

* PV/IDC multiplier = 0.8384

# PV/IDC multiplier = 0.8384

@ PV/IDC multiplier = 0.7878

4.2.4 Low Discount Rate

Table 4.5 presents benefit-cost ratios of conventional technologies, when their performance levels and costs conform to base levels (Table 3.8) and the annual discount rate is 10 per cent.

Table 4.5 : Low Discount Rate -- Benefit-Cost Ratios of Conventional Technologies

Capacity Factor (fraction)	B/C Ratios		
	CT*	CCP#	Coal TPS@
0.1	1.6923	1.1558	1.1754
0.2	2.4873	1.7107	1.8340
0.3	3.2394	2.2409	2.4605
0.4	3.9780	2.7662	3.0788
0.5	4.5878	3.2033	3.5924
0.6	5.0649	3.5480	3.9971

* PV/IDC multiplier = 0.8351

# PV/IDC multiplier = 0.8492

@ PV/IDC multiplier = 0.8029

4.3 Benefit-Cost Ratios of Windfarms

Owing to the fact that the power supply situation will be characterized by shortages in the foreseeable future, the value of energy generated by windfarms will be influenced by cost of unserved energy, load growth rates and generating capacity accessed by TNEB; and their benefit-cost ratios will also be influenced by the performance of conventional technologies and their costs, and real discount rates. Furthermore, the benefit-cost ratios associated with generation from windfarms will depend upon windspeed conditions, turbine size, windfarm size, and turbine and grid availability factors -- these issues however, are covered in the various windfarm output scenarios (Table 4.1).

Benefit-cost ratios of windfarms are computed for the following cases for each windfarm output scenario :

(i) Base : Using base case values for cost of unserved energy, load growth rate, capacity accessed by TNEB and real discount rate as given in Table 3.8;

(ii) High cost of unserved energy (Rs 3.226/kWh);

(iii) Low cost of unserved energy (Rs 1.243/kWh);

(iv) High load growth rate (10.74 per cent per annum);

(v) Low load growth rate (6.74 per cent per annum);

(vi) Low capacity accessed by TNEB (see Table 3.8);

(vii) High capacity accessed by TNEB (see Table 3.8);

(viii) Low performance and high costs of conventional technologies;

(ix) Enhanced performance and low costs of conventional technologies; and

(x) Low real discount rate (10 per cent per annum).

4.3.1 **Base Case**

Table 4.6 shows the benefit-cost ratios of windfarms under base case conditions. These ratios are to be compared with benefit-cost ratios for conventional technologies given in Table 4.2. It is evident that in no windfarm output scenario, are windfarms economically attractive vis-a-vis the conventional dispatchable technologies.

The capacity factors and effective capacities (kW/kW of installed capacity) for the various windfarm output scenarios are also given in Table 4.6. It is clear that for the same turbine and windfarm size, the benefit-cost ratio of investing in windfarms will increase with the increase in their capacity factors and effective capacities.

Table 4.6 : Base case — Benefit-Cost Ratios, Capacity Factors and Effective Capacities of Windfarms

Windfarm Output Scenario	B/C Ratio*	Capacity Factor (fraction)	Effective Capacity (kW/kW)
BASE	0.8073	0.178	0.158
HIGH	0.8551	0.183	0.165
LOW	0.6789	0.150	0.135
W450	0.7116	0.158	0.138
W100	0.8035	0.148	0.119
AVHI	0.8669	0.192	0.167
AVLO	0.7169	0.158	0.138
SMAL	0.8102	0.180	0.158

* PV/IDC multiplier = 0.8837;
OCC = Rs 14701/kW and annual O&M costs = Rs 0.19/kWh for W100;
OCC = Rs 18284/kW and annual O&M costs = Rs 0.20/kWh for other windfarm output scenarios.

4.3.2 Cost of Unserved Energy

If the cost of power shortages in the economy increase, the value of wind energy also increases vis-a-vis base case levels. A comparison of benefit-cost ratios given in Tables 4.7 and 4.6 shows this. Table 4.7 also gives the capacity factors for CTs, CCPs and coal based TPSs, within which windfarms break even with them. It is evident that investment in CCPs and coal-fired TPSs is relatively more economically attractive (than in windfarms at Kayathar and Talayathu) if the capacity factors of these two conventional technologies is to remain upto a little more than ten per cent. CTs however, remain the most economically attractive option.

Table 4.8 shows that if the cost of unserved energy is less than that of base case levels, the economic viability of windfarms deteriorates further.

Table 4.7 : High Cost of Unserved Energy# — Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio	Range of Capacity Factors within which the B/C ratio of a windfarm equals that of a *		
		CT	CC	Coal TPS
BASE	1.4170	<0.1	0.1-0.2	0.1-0.2
HIGH	1.5313	<0.1	0.1-0.2	0.1-0.2
LOW	1.1885	<0.1	0.1-0.2	0.1-0.2
W450	1.2441	<0.1	0.1-0.2	0.1-0.2
W100	1.3883	<0.1	0.1-0.2	0.1-0.2
AVHI	1.5227	<0.1	0.1-0.2	0.1-0.2
AVLO	1.2592	<0.1	0.1-0.2	0.1-0.2
SMAL	1.4181	<0.1	0.1-0.2	0.1-0.2

Other parameters as per base case conditions.

* Compare B/C ratios of windfarms with those of CTs, CCPs and coal-fired TPSs given in Table 4.2.

Table 4.8 : Low Cost of Unserved Energy# — Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio
BASE	0.7397
HIGH	0.7800
LOW	0.6224
W450	0.6525
W100	0.7387
AVHI	0.7941
AVLO	0.6567
SMAL	0.7428

Other parameters as per base case conditions.

4.3.3 Load Growth Rate

Table 4.9 given the benefit-cost ratios of windfarms if the annual load growth rate in the TNEB system increases to 10.74% (from 8.74% in the base case). Owing to increased demand -- and consequently more power supply shortages -- the economic viability of windfarms improves from base case levels. In fact, Table 4.9 shows that it would be better to invest in windfarms (at Kayathar and Talayathu) than in CCPs or coal-fired TPSs (if their capacity factors are anticipated to remain at a little more than 10 per cent or less), as long as neither of the three following situations arise : (i) windspeeds remain below normal levels during the economic lifetime of the windfarms; (ii) turbine and grid availability factors fall to as low as 90%; and (iii) large 450 kW wind turbines are used. However, CTs remain the most economically viable option.

Of course, if the load growth rate in the TNEB system remains below base case levels, the economic viability of windfarms is poor. This is evident from a comparison of the results in Tables 4.10 and 4.2.

Table 4.9 : High Load Growth Rate# — Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio	Range of Capacity Factors within which the B/C ratio of a windfarm equals that of a *		
		CT	CC	Coal TPS
BASE	1.0867	<0.1	0.1-0.2	0.1-0.2
HIGH	1.1204	<0.1	0.1-0.2	0.1-0.2
LOW	0.9150	<0.1	<0.1	<0.1
W450	0.9638	<0.1	<0.1	<0.1
W100	1.1114	<0.1	0.1-0.2	0.1-0.2
AVHI	1.1674	<0.1	0.1-0.2	0.1-0.2
AVLO	0.9654	<0.1	<0.1	<0.1
SMAL	1.0946	<0.1	0.1-0.2	0.1-0.2

Other parameters as per base case conditions.

* Compare B/C ratios of windfarms with those of conventional technologies, as given in Table 4.2.

Table 4.10 : Low Load Growth Rate# -- Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio
BASE	0.5643
HIGH	0.5892
LOW	0.4787
W450	0.4985
W100	0.5664
AVHI	0.6055
AVLO	0.5007
SMAL	0.5671

Other parameters as per base case conditions.

4.3.4 Capacity Accessed by TNEB

Table 4.11 gives the benefit-cost ratios associated with investment in windfarms at Kayathar and Talayathu, if the generating capacity accessed by TNEB reduces from base case levels (by a reduction in growth of power purchases to 2.58 per cent per annum from 1990 to the year 2000, as explained in section 3.2). It is evident from Table 4.11 that the relative economic viability of windfarms is very similar to that when the load growth rate increases (Table 4.9).

If the generating capacity at TNEBs command were to increase from base case levels, the economic attractiveness of the proposed windfarms would remain poor (Table 4.12).

Table 4.11 : Low Capacity Accessed by TNEB# — Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio	Range of Capacity Factors within which the B/C ratio of a windfarm equals that of a *		
		CT	CC	Coal TPS
BASE	1.0944	<0.1	0.1-0.2	0.1-0.2
HIGH	1.1281	<0.1	0.1-0.2	0.1-0.2
LOW	0.9220	<0.1	<0.1	<0.1
W450	0.9708	<0.1	<0.1	<0.1
W100	1.1200	<0.1	0.1-0.2	0.1-0.2
AVHI	1.1757	<0.1	0.1-0.2	0.1-0.2
AVLO	0.9723	<0.1	<0.1	<0.1
SMAL	1.1025	<0.1	0.1-0.2	0.1-0.2

Other parameters as per base case conditions.
* Compare B/C ratios of windfarms with those of conventional technologies, as given in Table 4.2.

Table 4.12 : High Capacity Accessed by TNEB# -- Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio*
BASE	0.5751
HIGH	0.6011
LOW	0.4856
W450	0.5078
W100	0.5779
AVHI	0.6171
AVLO	0.5103
SMAL	0.5776

Other parameters as per base case conditions.
* B/C ratios of windfarms remain the same in both cases of high TNEB accessed capacity given in Table 3.8.

4.3.5 Performance and Costs of Conventional Technologies

Table 4.13 gives the benefit-cost ratios of the proposed windfarms at Kayathar and Talayathu, in the event that costs associated with existing and committed TNEB capacity are higher than base case levels and performance levels are lower. If this were to happen, the economic viability of windfarms improves. However, unlike the cases of high unserved energy costs, high load growth rates and low generating capacity at TNEB's command, the windfarms under these conditions become economically attractive vis-a-vis CTs also, provided the latter are to have capacity factors of up to a little more than ten per cent and : (i) windspeeds do not remain below normal levels during the economic life time of the windfarms; (ii) grid and turbine availability are not as low as 90 per cent; and (iii) large 450 kW wind turbines are not used.

If the performance of conventional dispatchable generation technologies improves over base case levels, the economical viability of windfarms is adversely affected (Table 4.14).

Table 4.13 : Low Performance and High Costs of Conventional Technologies# -- Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio	Range of Capacity Factors within which the B/C ratio of a windfarm equals that of a *		
		CT	CC	Coal TPS
BASE	1.2533	0.1-0.2	0.2-0.3	0.1-0.2
HIGH	1.2987	0.1-0.2	0.2-0.3	0.2-0.3
LOW	0.9504	<0.1	0.1-0.2	0.1-0.2
W450	1.1113	<0.1	0.1-0.2	0.1-0.2
W100	1.2771	0.1-0.2	0.2-0.3	0.1-0.2
AVHI	1.3463	0.1-0.2	0.2-0.3	0.2-0.3
AVLO	1.1133	<0.1	0.1-0.2	0.1-0.2
SMAL	1.2604	0.1-0.2	0.2-0.3	0.1-0.2

Other parameters as per base case conditions.
* Compare B/C ratios of a windfarm with those of conventional technologies, as given in Table 4.3.

Table 4.14 : Enhanced Performance and Low Costs of Conventional Technologies# -- Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio*
BASE	0.5857
HIGH	0.6203
LOW	0.4996
W450	0.5165
W100	0.5816
AVHI	0.6289
AVLO	0.5201
SMAL	0.5884

Other parameters as per base case conditions.
* Compare B/C ratios of a windfarm with those of conventional technologies, as given in Table 4.4.

4.3.6 Low Discount Rates

A lower real discount rate means that a longer term view is taken towards power system expansion planning. The benefit-cost ratios of dispatchable technologies with a real annual discount ate of ten per cent are presented in Table 4.5, and for windfarms in Table 4.15. A comparison of the results given in the two tables reveals that in this situation, windfarms do not appear to be economically attractive.

Table 4.15 : Low Discount Rate# -- Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio*
BASE	0.9302
HIGH	0.9855
LOW	0.7817
W450	0.8201
W100	0.9270
AVHI	0.9991
AVLO	0.8262
SMAL	0.9337

# Other parameters as per base case conditions.
* PV/IDC multiplier = 0.9023;
Compare B/C ratios of a windfarm with those of conventional technologies, as given in Table 4.5.

4.4 A Likely Situation

It may very well be that as in the past, the performance of conventional dispatchable technologies remains below normative (base-case) levels[1], while cost and time over-runs continue to occur for adding new generating capacity. This will lead to a situation where the generating capacity owned by TNEB or/and accessed by it from the central sector agencies and other states in the southern regional grid, will be less than that assumed in the base case. Furthermore, the actual demand in the TNEB system may also be higher than that assumed in the base case (refer to section 3.2 and Table 3.1); and the economic costs of unserved energy may also be rather high.

In this situation, the economic viability of windfarms is considerably enhanced (Table 4.16). In fact, even if windspeed conditions remain below normal levels, or the turbine and grid availability situation is not very encouraging, or large 450 kW turbines are used, the proposed windfarms are a relatively more economically attractive option than CTs -- if the capacity factor of the CTs remains less than 30 per cent. For other conditions of windspeeds, grid and turbine availability and wind turbine size, the proposed windfarms become even more economically viable -- as CTs with capacity factors of upto 40 per cent, and CCPs and coal-fired TPSs of capacity factors of up to 60 per cent also show relatively lower benefit-cost ratios.

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[1] For instance, shortage of coal supplies in recent months have reduced the availability of certain thermal power stations meeting TNEB system demand.

Table 4.16 : A Likely Situation# -- Benefit-Cost Ratios of Windfarms

Windfarm Output Scenario	B/C Ratio	Range of Capacity Factors within which the B/C ratio of a windfarm equals that of a *		
		CT	CC	Coal TPS
BASE	2.9330	0.4-0.5	>0.6	>0.6
HIGH	3.0152	0.4-0.5	>0.6	>0.6
LOW	2.3643	0.3-0.4	0.5-0.6	0.4-0.5
W450	2.6037	0.3-0.4	>0.6	0.5-0.6
W100	3.0184	0.4-0.5	>0.6	>0.6
AVHI	3.1531	0.5-0.6	>0.6	>0.6
AVLO	2.6075	0.3-0.4	>0.6	0.5-0.6
SMAL	2.9573	0.4-0.5	>0.6	>0.6

Higher cost of CTs, CCPs and coal-fired TPSs compared to base case level, and poorer performance (see Table 3.8); unserved energy cost = Rs 3.226/kWh; annual load growth rate = 8.74 per cent; lower than base case level capacity at TNEB's command (see Table 3.8); other parameters as per base case conditions.

* Compare B/C ratios of a windfarm with those of conventional technologies, as given in Table 4.3.

V. CONCLUSIONS AND RECOMMENDATIONS

If the realities of the power supply situation are taken into account, the demand for power in the foreseeable future will continue to outstrip supply. In fact, there is a distinct possibility that the system load projections are underestimated and that new capacity that is expected to be added during the 1990s may not be commissioned as scheduled.

Under these conditions, the proposed windfarms compare rather favourably with conventional CTs, CCPs and coal-fired TPSs. The results presented in Chapter IV also indicate that the benefit-cost ratios associated with smaller windfarms may be marginally higher than for the proposed 50 MW and 25 MW windfarms at Kayathar and Talayathu respectively. However, the difference in the economic attractiveness of the two sizes of windfarms is rather small.

It is also evident that with low windspeeds and poor turbine and grid availability factors, the economic viability of windfarms suffers. However, windspeeds do vary from year to year and are not likely to remain low during the entire twenty year life span of the proposed windfarms. But efforts should be made to improve the system grid and to ensure that the wind turbines are available to generate power most of the time when windspeeds are favourable.

Likewise, the analysis also shows that the use of large 450 kW turbines is not suitable from the viewpoint of economic viability of the proposed windfarms. It therefore seems correct to deploy 225 kW wind turbines.

Annexure II.1: Formulation of the Windfam Capacity Responsibility Model

(1) Compute normalized frequency corrected load minus actual load for each hour and month.

$$ND(m,h) = \frac{FCL(m,h)-AL(m,h)}{\sum_{h}(FCL(m,h)-AL(m,h)}$$

where m : index for month (m = 1 for January, -----------, m = 12 for December).

h : index for hour (h = 1, -----, 24).

AL(.,.) : actual load at given system frequency (MW).

FCL(.,.) : frequency corrected load (MW).

Note : if (FCL(m,h)-AL(m,h)) < 0, then for analytical convenience, it is assumed to be "one".

(2) Compute monthly weights

$$W(m) = \frac{\underset{h}{\mathrm{Max}}(FCL(m,h)-AL(m,h))}{\sum_{m}\underset{h}{\mathrm{Max}}(FCL(m,h)-AL(m,h))}$$

(3) Compute windfarm capacity responsibility in MW per MW of installed capacity

$$WCR = \sum_{m}\Big(\sum_{h} ND(m,h) \,.\, WINDOUTPUT(m,h)\Big)W(m).$$

where WINDOUTPUT(.,.) = Windfarm output (MWh/MW of installed capacity).

Annexure II.2 : Computation of hourly hydro power generation levels for 1990.

(1) Compute hydro power generation in each six-monthly period.

$$HG(p) = AHG.f(p)$$

p : index for six-month period; p=1 for January to June and p=2 for July to December.

AHG : annual hydro power generation in 1990 from all hydro power stations.

f(.): fraction of the annual hydro power generation that occurs in given period.

Note : $f(1) = 1 - f(2)$

(2) Compute the hourly profile of hydro generation for each of the six months in a given period.

$$HG(m,h) = \frac{((AL(m,h) - BL(p))^{(E)}).\ HG(p)}{(\sum_{m} \sum_{h} (AL(m,h) - BL(p))^{(E)}).\ 30}$$

where m : index for month

h : index for hour

AL(.,.): actual load at given system frequency (MW)

BL(.): base load (MW)

E : exponent which gives the hydro dispatch on an hourly basis.

Note : (i) For p=1: m=1,-----, 6;
for p=2: m=7,-----, 12.

(ii) The hydro dispatch exponent 'E' is arrived at by conducting several simulation runs. An acceptable value for 'E' is one for which : (a) the hydro output so computed for each hour in each month does not exceed the installed hydro power capacity; (b) the share of generation computed thus for each month is not significantly different from the TNEB data; and (c) the thermal generation levels required hour by hour in each month do not vary too much. This procedure is attempted because hourly hydro power generation profiles were not readily available with TNEB.

(iii) A factor of 30 is used because the hourly load profiles for one day in each month are specified, while HG(p) gives the total energy generation in each six-month period.

Annexure II.3 : Computation of Benefit-Cost Ratios of Windfarms and Dispatchable Thermal Power Stations

(1) Compute the marginal cost of supplying energy from thermal power stations to meet demand

$$MC(m,h) = SC(TG(m,h)).(1+L)$$

where m : index for month

h : index for hour

TG(.,.) : thermal generation required to meet demand (MW)

SC(TG(.,.)): marginal cost of thermal generation required to meet demand (Rs/kWh).

L : average transmission and distribution losses (fraction).

(2) Compute the wind energy value (Rs/kW of wind capacity per hour)

$$WEV(m,h) = WINDOUTPUT(m,h).MC(m,h)$$

where WINDOUTPUT(.,.): Wind output (MWh/MW of installed capacity)

(3) Compute delivered energy value from windfarms

$$DEV(W,y) = \frac{\sum_{m}\sum_{h} WEV(m,h)}{\sum_{m}\sum_{h} WINDOUTPUT(m,h)}$$

Where W : index to indicate windfarms

y : index to indicate year (y = 1 for 1992;
y = 2 for 2000).

(4) Compute delivered energy value for the dispatchable technologies at given capacity factor.

$$DEV(D,C,y) = (\sum_{h} SORTMC(m,h))/H$$

D : index to indicate dispatchable technologies

C : capacity factor for dispatchable technologies (fraction).

SORTMC(.,.): values of MC(.,.) sorted in descending order.

H : number of hours over which SORTMC(.,.) is summed for a given value of 'C'.

Note : Steps (1) through (4) are done for the years 1992 and 2000.

(5) Compute annual average growth rates of delivered energy values from 1992 to 2000.

$$GDEV(W) = (DEV(W,2)/DEV(W,1))^{1/8}-1$$

$$GDEV(D,C) = (DEV(D,C,2)/DEV(D,C,1))^{1/8}-1$$

(6) Compute growth rate of delivered energy value of windfarms and dispatchable technologies beyond the year 2000.

```
If GDEV(W)>GSC or GDEV(W)<0
    then GDEVF(W) = GSC
    else GDEVF(W) = GDEV(W)

If GDEV(D,C)>GSC or GDEV(D,C)<0
    then GDEVF(D,C) = GSC
    else GDEVF(D,C) = GDEV(D,C)
```

where GSC : real escalation rate for outage costs.

GDEVF(.) : real escalation rate of delivered energy value of windfarms beyond the year 2000.

GDEVF(.,.): real escalation rate of delivered energy values of dispatchable technologies at given capacity factor, beyond the year 2000.

(7) Compute avoided variable cost if new generation capacity is established. The mathematical formulation for windfarms is presented below.

$$\mathrm{EB1(W)} = \frac{\mathrm{CRF(W).DEV(W,1)}}{(1+\mathrm{GDEV(W)})^{2}} \left\{ \frac{1 - \dfrac{1}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right)^{10}}}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right) - 1} - \frac{1 - \dfrac{1}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right)^{2}}}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right)^{10} - 1} \right\}$$

$$\mathrm{EB2(W)} = \frac{\mathrm{CRF(W).DEV(W,2)}}{(1+\mathrm{GDEV(W)})^{10}} \left\{ \frac{1 - \dfrac{1}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right)^{(\mathrm{CL(W)}+\mathrm{EL(W)})}}}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right) - 1} - \frac{1 - \dfrac{1}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right)^{10}}}{\left(\dfrac{1+\mathrm{DIS}}{1+\mathrm{GDEV(W)}}\right) - 1} \right\}$$

$$\mathrm{EB(W)} = \mathrm{EB1(W)} + \mathrm{EB2(W)}$$

where EB1(.) : cumulative discounted real energy benefits attributable to a windfarm from 1990 to 2000 (Rs/kWh, 1990 prices).

EB2(.) : cumulative discounted real energy benefits attributable to a windfarm from 2000 to the end of its economic life (Rs/kWh, 1990 prices).

EB(.) : total cumulative discounted real energy benefits attributable to a windfarm from 1990 to the end of its economic life (Rs/kWh, 1990 prices).

CRF(.) : capital recovery factor (fraction).

DIS : annual discount rate (fraction).

CL(.) : construction lead time (years).

EL(.) : economic life time (years).

Similarly, EB(D,C), the total cumulative energy benefits attributable to dispatchable generation technologies at various capacity factors can be derived.

Compute capacity benefits attributable to windfarms and the dispatchable power generation technologies. The mathematical formulation for a windfarm is presented below.

$$CB(W) = (EC(W).PVF(W).CAPPU(1+DIS)\hat{}EL(PU))/8760.CF(W).(1-TDL(W)).(1-AUX(W))$$

Where CB(.) : capacity benefit attributible to windfarms (Rs/kWh).

EC(.) : effective capacity of a windfarm (MW per MW of installed capacity)

CAPPU : overnight capital cost of a peaker unit (Rs/kW)

EL(PU) : economic life time of peaker unit (years)

CF(.) : capacity factor of a windfarm (fraction)

TDL(.) : transmission and distribution losses from energy generated by windfarms (fraction)

AUX(.) : auxiliary consumption of a windfarm (fraction).

Annexure III.1: TNEB's Capacity Expansion Program (MW)

			2000	
(MW)	1990	1995	Including Central Sector Share	Excluding Share of New Central Sect Projects
Coal/Lignite	3166	4628	5812	5628
Combustion Turbine	0	430	1186	730
Hydro	1945	1947.75	2127.75	2127.75
Nuclear	350	350	733	350
Wind	14	114	114	114
Total Installed Capacity	5475	7469.75	9972.75	8949.75
Total Effective Capacity	4050.19	5421.43	7229.43	6455.23

Source : Personal Communication, TNEB.